Applied Energy 210 (2018) 604–612

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Seasonal aspects of the energy-water nexus: The case of a run-of-the-river hydropower plant

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HIGHLIGHTS

- Seasonality patterns are a key aspect of the energy-water nexus.
- Changes in streamflow seasonality slightly affect future revenue.
- Changes in price seasonality may significantly affect the losses of revenue.
- Price seasonality brings about more uncertainty on revenue than climate change.

ARTICLE INFO

Article history:
Received 1 December 2016
Received in revised form 21 January 2017
Accepted 1 February 2017
Available online 10 February 2017

Keywords:
Nexus
Climate change
Seasonality
Uncertainty
Run-of-the-river hydropower
Alps

ABSTRACT

The energy-water nexus presents important implications at seasonal scale. For instance, electricity prices and streamflow have complex seasonal patterns and changes in both may adversely impact hydropower plant revenue. In order to quantify the effect of changes in price and water seasonality on future revenue distribution and its related uncertainty, we consider the case of a run-of-the-river plant. To this end, we integrate a hydrologic model, a hydropower model, two glacier inventories, six climate scenarios and five electricity price seasonal scenarios. Our results show that the impact of climate change on streamflow of the considered run-of-the-river plant will decrease the revenue by 20% in a business-as-usual price scenario. This decrease is mostly driven by a reduction of the annual streamflow due to glacier shrinkage rather than by the evolution of seasonality. From this perspective, the difference between the various climate scenarios is low. In contrast, change in electricity price seasonality induces a marked uncertainty in revenue. According to our scenarios, which assume no change in the mean annual electricity price, a change in price seasonality may indeed exacerbate or mitigate the impact of climate by 50 or 33% respectively, compared to the business-as-usual scenario. Our analysis highlights the need for considering intra-annual dynamics when investigating the energy-water nexus.

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1. Introduction

Water, energy and food are the most important elements supporting life, sustainable development and modern civilization [1]. Also, water and energy are intimately interconnected [2–4] and strategic in Europe [5]. Energy production may consume or divert water. Water availability and temperature may represent a stringent constraint in electricity generation [6–8]. In contrast, water supplying, treatment, and distribution require energy [9]. For instance, desalinisation is energy consuming. This interconnection is known as "energy-water nexus" [10].

Investigating water and energy as interconnected is fundamental for sustainable development and provides strategic information for decision makers, institutions, and economic stakeholders [10,11]. This nexus has been, however, poorly investigated in the literature, as water and energy have been generally studied as independent variables [9,12]. The need for reducing greenhouse gas emissions as well as the observed shortage of water resources due to over-exploitation and climate variability have recently posed the question of investigating the energy-water nexus in view of a more sustainable use of both [13].

An important case of the energy-water nexus is hydropower generation. Water is indeed centrally involved in energy

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http://dx.doi.org/10.1016/j.apenergy.2017.02.003
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generation by hydropower, which directly depends on the yearly hydrologic budget, including precipitation and snow melt [14]. In addition, investigating the nexus for hydropower is topical since it represents about 15% of the global electricity generation [15], and about 85% of renewable energy [16]. In several countries, it accounts for over 50% of all electricity generation including: Iceland, Brazil, Canada, Nepal and Mozambique [15]. Hydropower represents almost a quarter of the electricity in the western United States [17], and about 10% of the entire electricity consumed in the United States. It supplies over half of the electric energy mix in Austria (62%) and Switzerland (57%) [18]. Importantly, dams used for hydropower are usually multipurpose. As an example, the Hoover dam in California provides about 33% of freshwater used in Los Angeles and originally covered 75% of the necessary energy for the city [14].

Some hydropower plants can accumulate water in a reservoir, i.e., storage hydropower. These plants provide an operational flexibility that can compensate wind variability [19,20] or solar photovoltaic intermittency [21,22]. Storage hydropower may even be an energy-storage technology if the installation includes pumps, which are used to relocate water in an upper reservoir relying on surplus of energy when the demand is low [23]. Energy is thereafter generated when the price is high. This technology represents 99% of the large-scale electricity storage capacity in the world [24,25]. The management of the reservoir is the result of the equilibrium between water availability and energy demand [26]. Nonetheless, this management may represent an issue from an environmental perspective. While runoff affects energy generation, hydropower management influences water streamflow [27,28]. It also perturbs the whole water cycle by increasing the rate of evaporation [29]. In fact, hydropower has a water footprint [30,31].

The second main type of hydropower is the run-of-the-river scheme. One may generally find it in flat areas where the installation takes advantage of water volume rather than of the head of water [32]. It may represent an environmentally friendly option, since it does not significantly interfere with the river's flow [33]. But environmental impacts of hydropower substantially depend on local characteristics [34]. Run-of-the-river plants usually have no water reservoir, or a small one compared to annual streamflow. They generate base-load electricity, which varies with streamflow seasonality.

Recently, attention has been posed on the quantification of the impacts of climate change on hydropower [35], including an increase in temperature or a change in the spatial and temporal patterns of liquid and solid precipitation [36,37]. In mountain areas, precipitation and temperature may combine and result in a shift in the onset of snow melt [38] and a progressive decrease in peak snow accumulation [39,40]. Hydropower impacts are filtered by hydrological impacts and result in a decrease or increase in generation basing on local conditions [35]. Moreover, several hydropower plants worldwide are built downstream glaciers, which are, however, shrinking [36]. Glacier shrinkage may provide room to build new installations in areas currently covered by glaciers [41,42]. It also temporally provides increased meltwater through the so-called peak water [43,44], but this effect will progressively disappear in the future, thus resulting in a net loss of yearly water volume [38,44] and in associated impacts on ecosystems. Also, climate change may alter the seasonality of streamflow in snow- or ice-dominated catchments. Thus, climate change may hamper existing regulations and represent a reason for vulnerability of future hydropower [35,43].

This paper discusses the seasonal aspects of the energy-water nexus in the context of hydropower production and under a changing climate. In particular, we aim at showing how the correlation between water availability and electricity prices may affect revenue. This issue, sometimes neglected, is important because seasonality often triggers problems in the energy-water nexus, such as water stress or energy scarcity. When water availability is low compared to the demand, conflict of usage may occur. But it is not necessarily during dry years that the stress is high. In general, some specific seasons of the year face lack of water. The same issue occurs with the flood season [45], which generally takes place when precipitation is high during a short period. A larger amount of water during a short period may be in fact spilled rather than profitable [46]. It may occur even in a year with lower precipitation than the normal. The point is that climate change tends to exacerbate some of these issues and highlights the need for considering seasonality in the energy-water nexus debate.

In addition, many drivers may affect the future seasonality of electricity prices as well. First, the demand may increase in summer and decrease in winter because of global warming [47]. Second, the operational flexibility may increase thanks to the interconnection [48–50], demand-side management and smart grid [51–53], backup technology such gas turbine, or storage energy [54]. This is important because any increase in flexibility tends to smooth the price volatility and seasonality. Finally, the electricity price is determined by the supply too. With the increasing use of photovoltaic energy, summer electricity generation may significantly increase and this would decrease summer prices [55].

The originality of our paper resides in considering the evolution of both water and energy seasonality. There are plenty of investigations that independently consider the impact of climate change on either water seasonality or energy demand [56], but Madani et al. [57] argue the need for investigating them together. Some papers filled the gap considering catchment dominated by storage-hydropower plants [56–59]. These plants are rather robust to climate variability due to the possibility of adapting their storage management strategy [18,59]. Similarly, they may accommodate the possible variability in the seasonality of streamflow. Conversely, we consider a run-of-the-river power plant. To our knowledge, there has been little attention on the impact of climate change on this type of hydropower plants [60]. These are directly affected by climate change impacts on streamflow in terms of both quantity and seasonality because they do not have any regulation capacity. Therefore, such case studies bring more insights than storage-hydropower to understand the impacts of seasonality in the energy-water nexus. Contrary to already quoted research [56–59], we also consider that seasonality is not only affected by climate change. We therefore built five electricity price seasonality scenarios. This is another originality of the paper, which allows further understanding of the issue.

To perform our investigations, we integrate hydrological and hydropower models with electricity prices, for a specific run-of-the-river power plant. We opt for investigating a specific aspect and case study of the complex nexus, which is complementary to comprehensive approaches [61]. We consider two glacier inventories in order to account for the uncertainty linked to ice volume. We also use six climate scenarios to simulate future streamflow. Last but not least, we carry out a sensitivity analysis of the results to five specific scenarios of electricity prices rather than using some long-term electricity price seasonality projections, which are highly uncertain. The outcome is quantified in terms of energy generation and revenue. This is an intuitive and integrative way to understand the impacts of changing seasonality.

In Section 2, we describe the case study, the hydrological model, the future climate scenarios, the future price scenarios, and the method for the calculation of hydropower generation and revenue. In Section 3, we report the results in terms of seasonality of streamflow and electricity prices and we comment on the relevance of the results with respect the existing literature. Section 4

provides some general recommendations and applications. In the last section, we report our conclusions.

2. Methods and data

2.1. The case study

This analysis focuses on the Ceppo Morelli reservoir (Ceppo Morelli, Piedmont, Italy). The dam is 39 m high and presents a storage of about 100,000 m^3 [60,62]. This reservoir is smaller than that available at the time of construction, i.e., about 500,000 m^3 [63] due to progressive silting. The plant is now used in a run-of-the-river mode, i.e., daily streamflow is collected and used for energy generation with no relevant regulation by the reservoir [60]. This plant (including some minor streams) generates approximately 86–92 GWh per year (see [62], data for 2011–2013).

The reservoir at Ceppo Morelli collects water from the Anza river basin, a precipitation-, snow- and glacier-fed river. The total length of the Anza river at Ceppo Morelli is equal to 18.5 km, while the catchment area is equal to ~121 km^2. The mean discharge of the river is equal to 6.63 m^3/s. It presents, however, a strong seasonality with low flows in winter, and a spring-summer peak due to snow and ice melt [60]. The basin also includes about 7.67–12 km^2 of glaciers within an elevation range from 1760 m ASL to 3800 m ASL. The range of glacier area stems from inherent ambiguity in the available glacier inventories, i.e., the World Glacier Inventory WGI (see http://nsidc.org/), The New Italian Glacier Inventory IGI [64], and the Randolph Glacier Inventory RGI [65]. The only available study about the future of hydropower in this basin [60] shows that hydropower generation and glacier volume are both predicted to decrease by 2050. No information is available about the seasonal impact of climate change on revenue.

The available meteorological daily data include precipitation, temperature and snow depth at ~1300 m ASL (Macugnaga, from 2000 to 2013), air temperature and snow depth at ~2000 m ASL (Rifugio Zamboni, from 2007 to 2013), air temperature at ~2800 m ASL (Passo del Moro, from 2000 to 2013), and daily incoming streamflow at Ceppo Morelli (from 2006 to 2014). Precipitation at Macugnaga was corrected for rain gauge under catch [66] by reconstructing solid events from simultaneous snow depth data: see [60] for details.

2.2. Hydrological model, glacier inventories and climate scenarios

The hydrological model as well as the climatic scenarios are presented in detail in Bongio et al. [60], where it is also discussed the impact of climate change on hydropower generation up to 2050. Here, we summarize the most relevant information about the model and the scenarios, which are an input for our analyses up to 2065.

We simulated observed and future incoming streamflow at Ceppo Morelli using a conceptual semi-lumped hydrological model of the basin [60]. The input of the model includes precipitation and temperature at Macugnaga; precipitation is classified as rain or snow basing on a calibrated temperature threshold. Simulated fluxes are infiltration and surface runoff, evapotranspiration, snow accumulation and melt, ice melt, and groundwater flow. The basin is subdivided in a set of elevation bands to capture the spatial patterns of the hydrological processes and their change with elevation, which represents the key driver of mountain hydrology. A mass balance of the glacier system is also included, but glacier movement is neglected for simplicity. The hydrologic budget is computed at daily resolution to solve a trade-off between computational time and the simulation of the expected seasonality of the Anza river. This modelling framework has been tested using data of the incoming streamflow at the dam and has proven to provide a sufficiently good performance for the scopes of this paper, e.g., a Root Mean Square Error between 2.87 and 6.05 m^3/s, a Nash Sutcliffe Efficiency between 0.71 and 0.89, and a volumetric deviation for cumulative yearly water volume between −4.94% and 7.61%. Further details, including the protocol of calibration, may be found in Bongio et al. [60].

To derive future scenarios of streamflow at Ceppo Morelli, we follow Bongio et al. [60] and use three different types of climate scenarios (henceforth, scenarios A, B and C). They are based on direct assumptions about future climatic patterns, i.e., imposed changes in temperature and precipitation compared to present observations. This "locally-based" approach is preferred to the use of IPCC-like outputs from the combined run of Climate Scenarios and Representative Concentration Pathways because they are conceived to easily provide an uncertainty assessment via Monte Carlo analysis. Moreover, they can provide an easy-to-use benchmark for decision makers. In Bongio et al. [60], outputs of scenarios A, B and C are also compared with two IPCC-like scenarios: the approaches provide comparable results.

Scenario A (*future-like-present*) assumes the perpetuation of present short-term weather conditions. All available data of precipitation and temperature in Macugnaga are used to randomly extract 200 time-series of forcing data. The extraction is made on a yearly basis and using water years: in this way, intra-year dependency is preserved, whereas any inter-year dependency is lost. Then, all these 200 time-series are used to force the hydrological model from 2015 to 2065 to build 200 future paths of streamflow and energy generation and then to obtain confidence intervals using a 0.05 significance level. The model run is repeated using two different glacier inventories to consider glaciological uncertainty. These inventories are WGI and RGI, which represent the upper and lower boundary of estimated initial glacier extension for this area (see [60] for details). Note that the extraction of the 200 input time-series is repeated when changing the glacier inventory. During a first run the mass balance of glaciers is neglected (that is, the volume of glaciers is kept constant during the entire simulation horizon, scenario $A1_{WGI}$ and $A1_{RGI}$); during a second run the mass balance of glaciers is allowed (scenario $A2_{WGI}$ and $A2_{RGI}$). A1 investigated the sole effect of weather variability on hydropower, whereas A2 highlights the effect of glacier shrinkage on future electricity generation. $A1_{WGI}$ and $A2_{WGI}$ indicate results obtained using the WGI glacier inventory; $A1_{RGI}$ and $A2_{RGI}$ refer to outputs using RGI. This convention will be used for all other scenarios as well.

Scenario B includes a positive trend in air temperature, while no trend in precipitation is included. This is because available observations over the study area do not support the existence of a clear trend in precipitation for western Italian Alps [67]. Three trends are chosen and added to 200 randomly extracted time series of temperature. These trends are +0.03 °C/yr (B1), +0.06 °C/yr (B2), and +0.09 °C/yr (B3). Note that +0.03 °C/yr is consistent with available observations for the study area [67]. The extraction and then the model run are repeated when changing either the glacier inventory or the temperature trend.

Scenario C considers no trend in temperature or precipitation, but assumes that all precipitation falls as liquid. This represents a theoretical limit case for a snow-dominated catchment, and highlights the role of the loss of seasonality on the hydrological cycle. In this case, 200 time-series of precipitation and temperature are randomly extracted, and all precipitation is classified as liquid. The extraction and then the model run are repeated when changing the glacier inventory (C_{WGI} and C_{RGI}). Overall, we have considered six climate-glacial scenarios (henceforth, simply climate scenarios): A1, A2, B1, B2, B3, C.

2.3. Electricity price and scenarios

In the 1990s, Italy started the liberalization of the electricity market [68]. Enel, the main electricity supplier, became a limited company in 1992. In 1999, the Decree 79 triggered the gradual opening to the competition. A wholesale electricity market has been established and is managed by Gestore Mercati Energetici [69]. It provides hourly electricity prices from 2004, which are considered in this study and shown in Fig. 1.

In order to identify and quantify the frequency, amplitude and shift of the main periodicity, we performed a Fourier transform (FT) analysis of the electricity price time series. Here, the first two orders, i.e., annual and biannual cycles, are considered, summed and reported in Fig. 1. The analysis of Fig. 1 shows that Italian electricity prices tend to peak in winter and summer when the consumption increases for heating and cooling, respectively. The price generally decreases during spring and autumn.

Price scenarios are built to analyse the sensitivity of hydropower revenue on their seasonality. As already said, predicting future long-term price seasonality is unreliable and dominated by uncertainty. We therefore follow an alternative approach based on "what-if" scenarios. Five basic price scenarios are developed. Each considers a specific seasonality pattern based on the one identified in Fig. 1, as described below:

(1) Business as usual (BaU): This scenario assumes that the seasonality will remain the same as the historical one. This represents a reference scenario.
(2) Without seasonality (WS): Here, we neglect seasonality. There is no season when the price is higher or lower than the others.
(3) Inverted seasonality (IS): This scenario assumes a shift of seasonality by six months. The winter peak becomes higher than the summer one, while the summer peak is currently higher than the winter one.
(4) Shifted seasonality (SS): This scenario assumes a shift of seasonality by three months. The peaks are during spring and autumn instead of during winter and summer.
(5) Doubling seasonality (DS): This scenario considers that the amplitude of current seasonality doubles. It reinforces the periodicity.

Fig. 2 shows the average monthly price and its volatility for the five scenarios. We assume that the volatility term is the remaining error once the seasonality is removed from the price time series. We fitted it with a kernel distribution. Note that by modifying the seasonality, the mean price may change. A constant factor corrects each scenario in order to keep the mean prices at the same level as the historical ones. It removes any bias in order to focus the analysis on the impact of seasonal changes.

2.4. Energy and revenue computation

Various hydropower models have been developed [70], such as EBHOM [71], BPMPD solver [72], Dynamic Programming algorithm [26], benefit and risk balance optimization model [73]. But, in a run-of-the-river plant, the hydropower model is very simplified, as explained in Bongio et al. [60]. Indeed, the operational flexibility is low or null. The daily hydropower generation is determined by the streamflow up to a threshold, 10 m^3/s in our case. We assume that additional flows are released. In order to take into account the contribution of minor streams in the valley, a constant amount of 1 m^3/s is added every day [60]. The conversion from water flow to energy generation considers an efficiency of 0.81. Note that this approach neglects any ecological or residual streamflow requirement at the plant (about 0.7 m^3/s).

The revenue is then computed by multiplying the electricity generated by the corresponding hourly price, while the annual revenue is the addition of the 8760 hourly revenues. Because 10 years of electricity prices are available and 200 streamflow simulations are generated, a total of 2000 annual revenue can be calculated for each scenario by combining each price trajectory with each streamflow simulation. These results are summarized using a distribution of revenue, which is based on the principle of Monte Carlo approach.

3. Results and discussion

3.1. Climate change and streamflow seasonality

Fig. 3 shows the prediction of monthly average streamflow for the water years 2064–2065 at Ceppo Morelli using the different

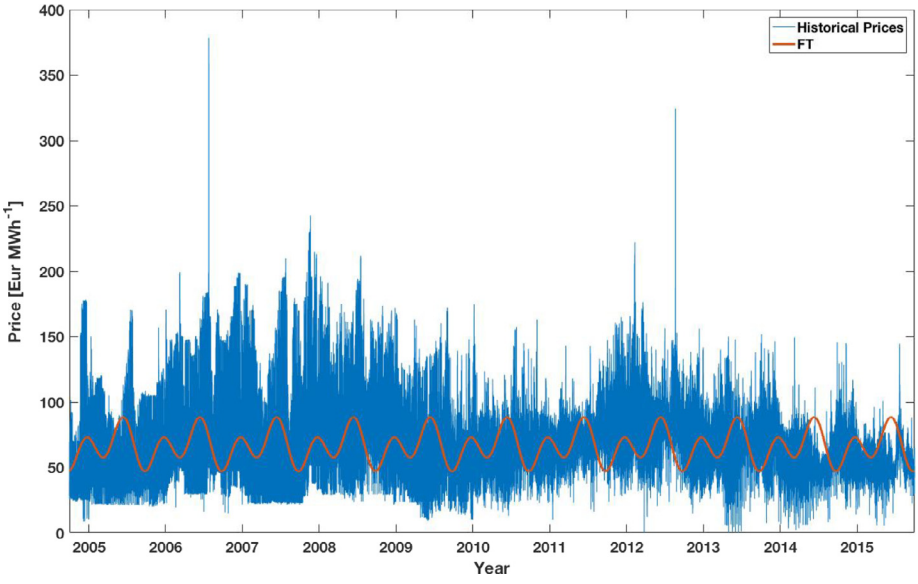

Fig. 1. Historical prices and periodicity obtained with a Fourier Transform (FT).

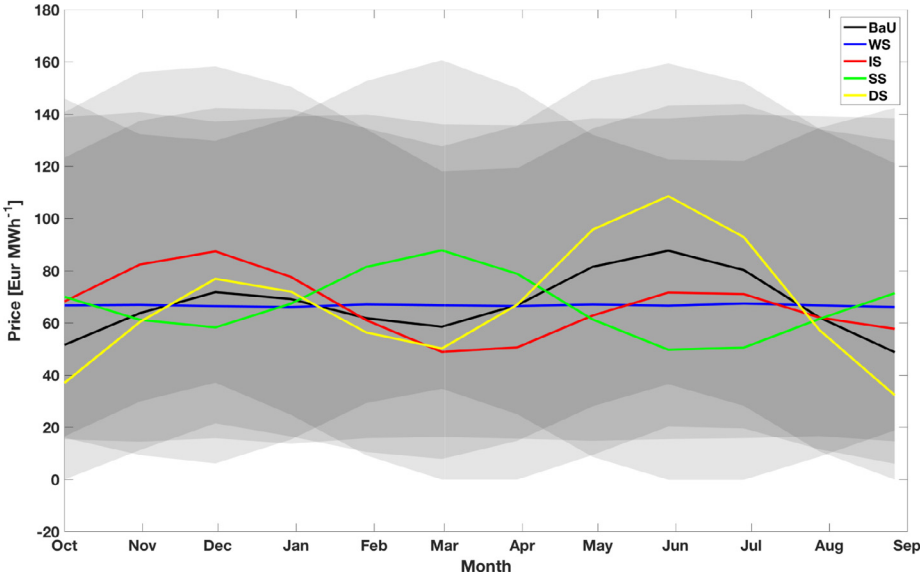

Fig. 2. Mean monthly prices for the five price scenarios. Grey areas are the volatility of price (0.05 significance level). A darker band means overlapping of confidence intervals.

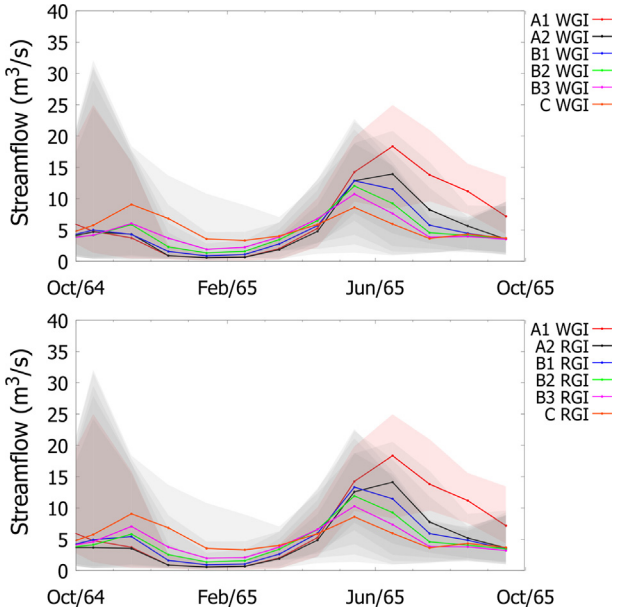

Fig. 3. Predicted average monthly streamflow in 2064–2065 for the different scenarios, and the two glacier inventories: WGI (upper panel) and RGI (lower panel). Grey and red areas are confidence intervals (0.05 significance level). A darker band means overlapping of confidence intervals. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

climate scenarios and the two glacier inventories: WGI in the upper panel, RGI in the lower panel. Scenario $A1_{WGI}$ represents a reference condition of unvaried climate and glacier extension. It is also reported in the lower panel of Fig. 3, because its predictions are very similar to those by $A1_{RGI}$ [60]. $A1_{WGI}$ exemplifies the current patterns of runoff seasonality, i.e., a marked peak in summer and a minimum in winter. Accordingly, current streamflow seasonality in the Anza basin is dominated by snow and ice melt [60].

All the other scenarios show a decreased peak in streamflow during spring and summer, which is due to the progressive shrinkage of glaciers. Also, a warmer climate reduces snow events and, therefore, spring snow melt. A transition from snowfalls to rainfalls also entails a faster response in terms of streamflow, which is the reason for increased variability of monthly streamflow, namely, larger confidence intervals during autumn or winter than those for A1 for all the scenarios. The stronger the increase in temperature is (i.e., from A2 to B3), the lower is the peak of streamflow during summer due to increased depletion between 2015 and 2065. Conversely, winter low flow increases with the temperature trend. Overall, climate change is expected to reduce the current seasonal patterns of streamflow and to drive a transition from an ice- and snow-dominated regime to a precipitation-dominated regime [see e.g. 35,38]. Scenario C clearly reproduces this limit case: streamflow is maximum in autumn and spring, whereas it is minimum in winter and summer. This is consistent with the observed intra-year patterns of precipitation events in northern Italy.

3.2. Impact of streamflow and electricity price seasonality on revenue

Fig. 4 shows the probability distributions of the annual revenue, in the period 2060–2065, using the BaU electricity price, i.e., assuming no change in price seasonality. Firstly, compared to the present revenue (in black), all scenarios predict a decrease in revenue. Surprisingly, the mean revenue shows only small variations from one climate scenario to the others. Although climate change does affect revenue, the impact is slightly affected by future temperature-precipitation scenarios. This is because here the dominant process is a decrease in streamflow and this is consistently predicted by all the scenarios [60]. This outcome confirms a conclusion observed in Switzerland [74], that is, the effects of climate change on streamflow may not represent a high source of uncertainty for revenue computation in alpine, glacierized areas, since the variance amongst the various scenarios is generally low. Even the epistemic uncertainty in initial glacier area does not affect significantly the future revenue distribution. Indeed, the difference between RGI and WGI is low. This conclusion may be, however, partially affected by the calibration procedure [60].

Secondly, the variability of annual revenue tends to increase in all but A2 temperature - precipitation scenarios. The historic standard deviation is 0.81 [Millions Euros]. RGI-based revenues have a standard deviation of 0.78(A2), 0.83(B1), 0.89(B2), 0.92(B3), 0.82 (C) [Millions Euros]. WGI-based revenue standard deviations change to reach 0.77(A2), 0.83(B1), 0.89(B2), 0.89(B3), 0.82(C)

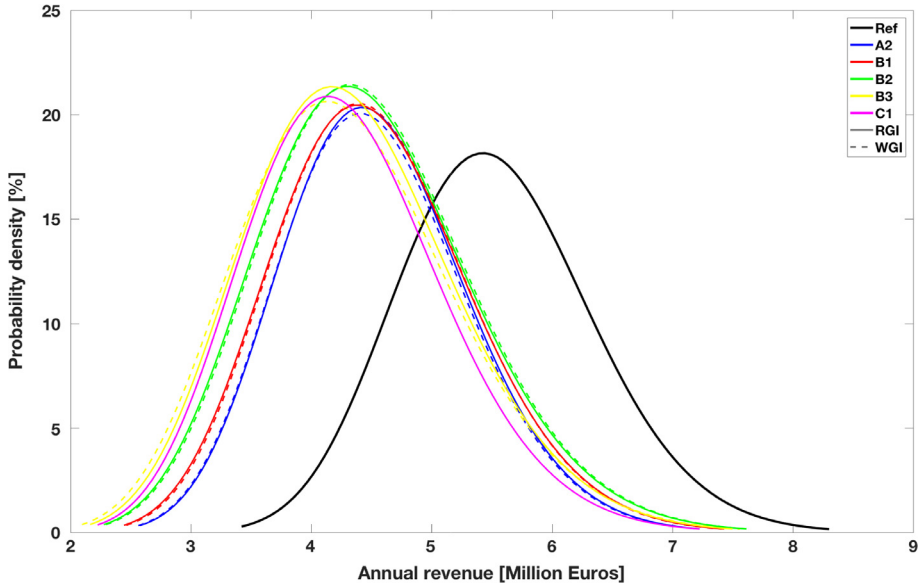

Fig. 4. Probability distribution of the annual revenue, in the period 2060–2065, for various climate scenarios and both glacier inventories, i.e., RGI (solid line) and WGI (dotted line), in the case of BaU price scenario. The distribution of annual revenue associated with the present condition is reported in black.

[Millions Euros]. A higher variability is bad news from the hydropower operator perspective. It increases the uncertainty of year-to-year revenue, which may prove to be challenging in terms of management [60].

Fig. 5 shows the variability of annual revenue due to a variation of price seasonality according to scenarios WS, IS, SS and DS. Here, the historical streamflow is considered. Compared to the present situation (in black), Fig. 5 shows that removing or shifting price seasonality tends to reduce annual revenue (WS, IS and SS). In contrast, the revenue increases when the current seasonal pattern is doubled (DS). This result highlights the impact of a correlated (or not correlated) seasonality between the resources, here water, and the demand, represented here by the electricity price. A comparison between Figs. 4 and 5 shows that the decrease in present revenue due to changes in price seasonality is slightly smaller than that due to future changes in streamflow. However, the differences between revenue distributions are greater when considering various electricity price patterns at present than various climate scenarios in the future.

Table 1 shows the variation of the mean electricity generation and revenue between 2015–2020 and 2060–65. In the BaU scenario, the revenue variations are close to those corresponding to the electricity generation. Again, this means that a change in runoff seasonality has low impacts on revenue. We may have expected that the large drop of streamflow in summer could lead to a larger drop of revenue than electricity generation.

In contrast, the relative difference in revenue between the five electricity price scenarios is large, even if the annual mean price is constant. By comparing BaU with SS, it is shown that changes in price seasonality can exacerbate by up to 50% the drop of revenue induced by decreased streamflow. For instance, the drop of revenue in BaU is about 20% (BaU) when it goes near 30% (SS) in

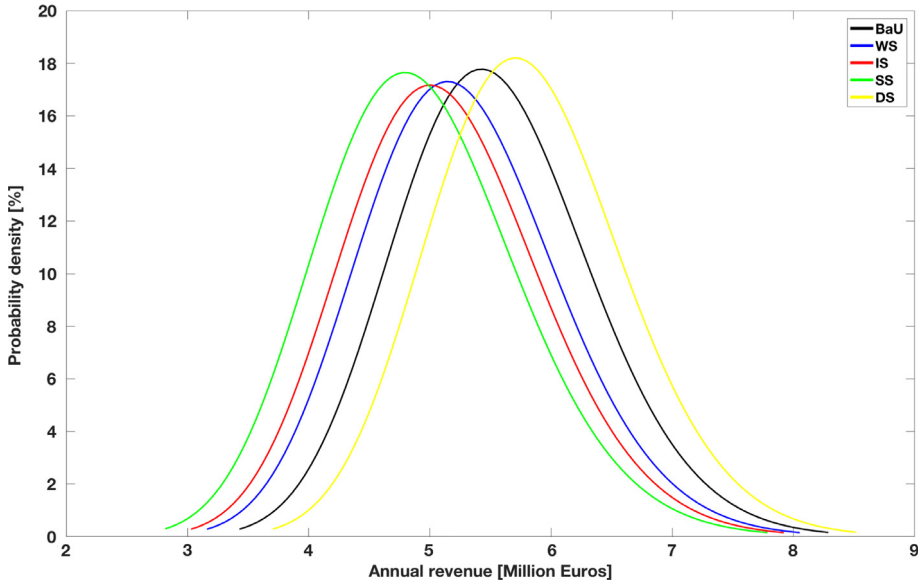

Fig. 5. Probability distribution of the annual revenue associated with the five price scenarios considering the historical streamflow.

Table 1
Difference (%) between 2015–2020 and 2060–2065 for different climate scenarios and glacier inventories, in terms of electricity generation and revenue using five price scenarios: BaU, WS, IS, SS and DS.

Electricity generation difference [%]		WGI						RGI				
		A1	A2	B1	B2	B3	C	A2	B1	B2	B3	C
		0	−20	−19	−19	−20	−20	−20	−19	−19	−21	−20
Revenue difference [%]	BaU	0	−18	−18	−19	−22	−22	−18	−18	−19	−22	−22
	WS	−5	−24	−23	−23	−24	−24	−24	−23	−23	−25	−24
	IS	−7	−25	−24	−24	−25	−23	−25	−24	−24	−26	−23
	SS	−11	−29	−27	−25	−26	−25	−29	−27	−25	−26	−25
	DS	5	−12	−13	−16	−19	−21	−12	−13	−15	−19	−21

the A2 scenario. If current seasonality doubles, the impacts of climate change will be, conversely, mitigated by up to 33%. In the A2 case, the mean revenue decreases of 12% (DS) rather than 18% (BaU). In fact, the uncertainty caused by possible changes in the seasonality of electricity price is higher than the uncertainty in future streamflow. Indeed, changes in streamflow decrease revenue by 20 ± 2%, but the variation amongst the streamflow scenarios is low, only 2%. On the other hand, the difference between the worse and best price scenario can be up to 17%, from a decrease of 12% to 29% in the A2 climate scenario.

Last but not least, the price scenario has no significant impact in the C climate scenario. In that situation, streamflow has a reduced seasonality (Fig. 3). Therefore, it sounds logical that the price seasonality has no impact on revenue. This limit scenario highlights that our approach is consistent and that the dependence between streamflow and price seasonality plays a key role.

4. Application and recommendations

Previous studies on the impact of climate change on hydropower show that results are very site-specific [75,76]. Even neighbouring catchments may face opposite impacts of climate change [77]. In addition, electricity price seasonality may vary in each region since the consumption pattern and supply mix differ. Therefore, the quantitative results are limited to the Ceppo Morelli case study and it is challenging to generalize our results. Nevertheless, we can provide some qualitative, general recommendations for similar applications.

First, this paper shows that seasonality correlation between streamflow and electricity prices highly matters for investigating the energy-water nexus. Non-correlated seasonality may indeed be worrying. It can exacerbate the impacts of climate change and the conflict of water. In fact, in many situations, the annual amount of runoff does not represent an issue by itself. The critical point is when the temporal distribution in a year is not correlated to the demand. This result shows the complexity of the energy-water nexus. Although investigations of annual values may draw helpful conclusions, some investigations need a higher temporal scale. Researchers should, therefore, ask themselves which is the right temporal scale for each case study. In case of run-of-the-river power plants, a seasonality analysis has generally high relevance. But such a deep investigation may not be required if water or energy possesses a reduced seasonality. For instance, in climate scenario C the streamflow was almost constant over the year. In that situation, a change in price seasonality does not affect the results and there is no need for building many price seasonality scenarios.

Second, we can draw some conclusions for Europe too. Runoff and price seasonality are case-specific, but some general patterns do emerge at the continent scale. The hydropower plants in mountain regions generally experience a large streamflow in summer when glacier and snow melt. Regarding the electricity price, it tends to peak in winter. As shown in our Italian case, a second peak occurs in summer in southern Europe. Based on these general trends, we can generalize our results. Unless the current price seasonality is intensified, like in the DS price scenario, the revenue will likely be negatively affected by the new price seasonality pattern. This outcome may support investment assessments in new infrastructure or retrofitting. If decision makers consider scenarios looking at mean price evolution only, which is often done in practice, they must probably consider that revenue may slightly drop because of the new price seasonality.

Third, our results bring insight into future uncertainty too. This issue is very relevant and new investment assessments should consider that aspect. Particularly in long-term planning, both climate change and uncertainty must be considered [78]. One should distinguish between epistemic uncertainty, i.e., limits of our knowledge, and variability, i.e., inherent natural randomness [79]. If epistemic uncertainty dominates, one should try to reduce it with further scientific research. In contrast, in context with high variability, the project manager must try to increase the managerial flexibility of the project [74], as it allows adapting the installation to future unforeseen events. In our case, the uncertainty in future scenarios of streamflow is little, as all the scenarios predict a reduced generation between −19% and −21%. Since hydropower plant lifetime is about 80 years [80], this should be accounted in the investment assessment. But the analysis of only one climate scenario may be considered in similar conditions, i.e., where a dominant mechanism of glacier depletion reduces the variation amongst climate scenarios. In contrast, the electricity price evolution brings large inherent randomness. The project manager should consider the adaptability of the power plant. Indeed, taking a decision on the basis of scenarios could lead to unsatisfactory design.

Finally, our results have policy relevance. Hydropower represents 85% of global renewable energy generation [16]. But European hydropower plants are in financial trouble because of the electricity price drop [81]. We show that the new energy policy, which is more likely to lead to the WS, IS or SS scenarios, rather than the DS one, is likely to exacerbate the situation for run-of-the-river power plants because of change in electricity price seasonality. Policy makers are advised to consider this effect in their analysis, since it can jeopardize the profitability of hydropower plants. It can have a large impact since this technology facilitates the decarbonisation of the energy sector [16] and the penetration of wind and solar energy [82].

5. Conclusion

We developed a specific case of the energy-water nexus by investigating a run-of-river hydropower plant. Results show that correlation between water availability and energy price tends to mitigate the impact of climate change. In contrast, the situation can get worse if the periodicities become uncorrelated. Without considering changes in mean electricity price, we show that

changes in price seasonality can relatively increase by up to 50% or decrease by about 33% the losses of revenue due to decreased streamflow in a business-as-usual price pattern. On the contrary, while climate change affects future revenue, all climatic scenarios lead to a consistent decreasing of about 20% of generation. Therefore, whatever the future climate, the operator can quantify the expected loss because changes in streamflow bring about low uncertainty.

There is room for further investigations. The water and energy interactions are complex and this complexity may be investigated by more comprehensive analyses. Some papers try to include all interactions of the energy-water nexus in order to draw conclusions. In that direction, a systemic analysis may be considered. In our case, we chose a bottom-up approach. We investigated a case study in order to discuss a simple situation that allows going further into details. Then, the results are qualitatively generalized. In fact, both approaches, comprehensive and specific, are complementary in order to understand the energy-water nexus as a whole.

Acknowledgements

Authors would like to thank Edison, the company that manages the Ceppo Morelli reservoir, for providing measured data at Ceppo Morelli, and the Piedmont regional administration for providing meteorological data and glaciers locations and extension according to WGI. We thank the Gestore Mercati Energetici for providing electricity price data. We thank the Politecnico di Milano, University of Geneva and Imperial College London for providing the required infrastructure for the research. Dr. Ludovic Gaudard thanks the Swiss National Science Foundation, which supports his research in the framework of the Swiss National Research Program 70 (Energy Turnaround). Fruitful discussions with Dr. Mauro Spanò, Dr. Davide Rabuffetti and Dr. Franco Romerio are acknowledged.

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